EXHIBIT 3
DATE 1/16/13
HB 188

(3)

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's Application for Approval of Avoided Cost Tariff - Schedule QF-1	)))	REGULATORY DIVISION DOCKET NO. D2012.1.3

CONCURRING OPINION OF COMMISSIONER TRAVIS KAVULLA

Regulation is a substitute for competition in certain monopoly industries, including the electric utility sector. That is the core premise of what economic regulators of monopolies such as this Commission do. Services in a perfectly competitive market ultimately will be priced at their marginal cost, the cost at which the industry could produce the next unit of the product being supplied.[1] In this proceeding, the Public Service Commission ("Commission") makes its best educated guess at determining the marginal cost of the utility's next required unit of electrical generating capacity and energy, on the basis of a utility's planned future acquisitions. This concept, called "avoided cost" in law, is defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The avoided cost the Commission establishes in this proceeding is then offered as a rate paid to small generators who, otherwise, would be shut out of the market entirely.

Regulation is always an imperfect substitute for competition. Through the rates we establish in this proceeding, however, the Commission ensures that some small semblance of the free market is present in a latently monopolistic industry which, left to its own devices, would charge customers high, uneconomic rates and block any generation on the system but its own. The avoided cost rates establish a more even playing field for the utility, with its ambitions to own generation and sell energy to itself, and independent producers, which compete with the

[1] *See e.g.* Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Vol. I, pp. 70-71 (Cambridge: MIT Press, 1988); read into the record at Hrg. Transcr. 153:5-19 (Sept. 12, 2012) ("9/12 Tr.").

QF-1 on NorthWestern Energy's system:

Table No. 7

NorthWestern Energy QF-1 Contracts				
Resource	Nameplate Capacity (MW)	Peaking Capacity (MW)	Annual Energy (MWH)	Expiration Date
Gordon Butte	9.6	0.0	33,571	2036
Musselshell 1	10.0	0.0	26,321	2036
Musselshell 2	10.0	0.0	25,797	2036
Two Dot	9.7	0.0	35,762	2036
Fairfield	10.0	0.0	32,160	2036
Agnew Ranch	0.2	0.0	58	2014
Boulder Hydro	0.3	0.0	1,413	2022
Martinsdale	0.5	0.0	1,133	2028
Martinsdale South	1.2	0.0	1,998	2028
Mission Creek	0.1	0.0	82	NK
Montana Marginal	0.5	0.0	236	NK
Moe Wind	0.8	0.0	641	2028
Pony	2.0	0.0	1,498	2025
Sheep Valley	0.1	0.0	870	2028
UMGF	0.2	0.0	3,916	NK
Wisconsin Creek	0.5	0.0	1,065	2014
Total:	56	0	166,521	

utility's generation division to provide the most affordable power to the utility's retail division and its captive customers.

While the following is not an attempt to describe every aspect of my agreement, enthusiastic or skeptical, with the Order, it is intended to offer some further rationale as to why I support it.

THE QF-1 TARIFF

Introduction and Summary

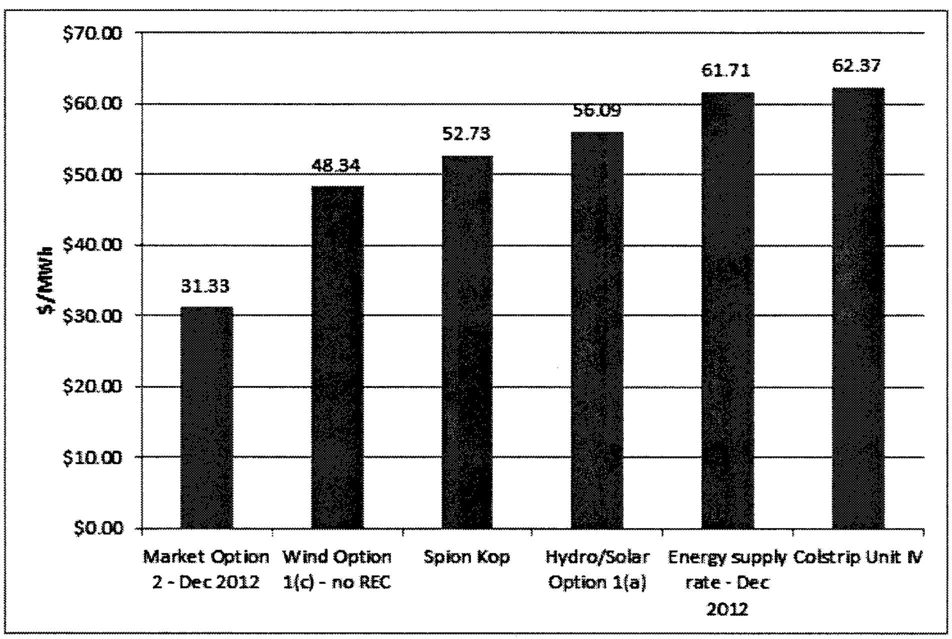
The QF-1 Tariff establishes the rates as well as terms and conditions for small power generators seeking power purchase agreements with NorthWestern Energy ("NorthWestern"). In the parlance of the Public Utility Regulatory Policies Act of 1978, these small generators are called qualifying facilities ("QFs").

The Option 1 rate and its three sub-options reflect the cost that is "avoidable" based on what NorthWestern selected through portfolio modeling as the least-cost, least-risk facility in its 2011 Electricity Supply Resource Procurement Plan ("2011 Plan"). Specifically, NorthWestern plans to acquire a large, gas-fired combined-cycle combustion turbine plant ("CCCT"). *See* 2011 Plan, Docket N2011.12.96, p. 185 (Dec. 15, 2011). Separately, NorthWestern Energy ("NorthWestern") selected a simple-cycle combustion turbine plant ("SCCT") that can be called upon less frequently than would a CCCT, to provide capacity that can be called upon to meet customers' needs during peak hours of demand. If the rate is correctly designed, QFs paid under the Option 1 sub-options will deliver electrical energy at the same cost to ratepayers as a CCCT, no more or less, with capacity value being paid through another proxy, the SCCT. *See supra* Ord. 7199d ¶¶ 18-55 (describing how QF-1 Tariffs are determined). It is appropriate that QFs enjoy the assurance of a long-term option because the utility itself enjoys the assurance of long-term recovery of all its investment costs, whether or not a utility-owned plant proves in the future to have been an above-market or below-market investment. Costs associated with a utility-owned asset are only disallowed if the plant, when it was built, was imprudently conceived or if the plant is somehow imprudently operated—a risk of loss a QF also bears.

The Option 2 rate, meanwhile, is not an estimate based on an avoided resource, but is instead based on market prices and does not come with the assurance of a long-term fixed rate. Unlike the Option 1 rates, Option 2 pays what energy freely available on the hourly market costs.

These rates are not carve-outs for wind farms or other projects, and the rates do not reflect what it would cost to build a wind farm.[2] Giving wind developers a leg-up is not the purpose of this proceeding, which is instead to establish a neutral price point. If wind can compete at that price, then developers will build wind. If wind is not economical, this avoided-cost proceeding erects the only barrier that should matter—an economic one—to forestall the development of uneconomical assets. Criticisms of QF policy because QFs often happen to be wind resources are misplaced, and ironically they do harm to the very principle—a competitive market based on neutral price points with no artificial advantage to any resource—that those calling for consumer protections and least-cost supply ostensibly support.

The rates resulting from this proceeding are quite low—lower than the average cost that NorthWestern customers pay for energy supply, lower than any of NorthWestern's own generating assets, indeed probably too low at the time being for developers of wind sourced qualifying facilities to develop a project.



It is paradoxical that the long-term levelized cost of a new power plant is lower than the current cost of NorthWestern's energy supply, but that nonetheless is a reasonable prediction at a

[2] The Commission previously established a QF rate based on the avoided cost of a wind resource because of NorthWestern's identification of a wind farm as preferred and economical resource in its 2007 Electricity Supply Resource Procurement Plan, making wind an "avoidable" resource. *See* Ord. 6973d, Docket D2008.12.146, ¶¶ 145-148 (Apr. 13, 2010). The Commission's last avoided-cost docket eliminated this carve-out. *See* Ord. 7108e at ¶¶ 71-77. Once more this Docket does not formulate an avoided cost based on a wind farm because NorthWestern's 2011 Plan does not include any plans for more wind farms.

time when long-term natural gas prices have undergone a nearly unprecedented decline. Since natural gas prices are the single most impactful input in the methodology to calculate a CCCT's avoided cost, the avoided cost rate has declined largely commensurate with gas forecasts' predictions.

Natural Gas Price Forecast

NorthWestern proposes for the second time in an avoided-cost docket to use a natural gas forecast that takes several years of futures prices from AECO, the Alberta pricing hub for natural gas, and then subjects them to the 2.16% implicit price escalator that is the measure of economy-wide commodity price inflation determined by the average of the changes of the Gross Domestic Price index, sampled each quarter from 1991 to 2011. (*See* Data Response ("DR") UMX-048c (Aug. 21, 2012)). The utility offers no evidence that natural gas prices escalate in tandem with other commodities in the economy. The past decade shows just how out-of-sync and volatile natural gas prices can be, with spikes causing it to outpace other commodity prices, and declines driven by technological revolutions that are specific to the exploration and production of oil and gas.

NorthWestern's natural gas forecast thus relies on a flawed method and, as at least one party argues, it is not really a forecast at all. (*See* United Materials of Great Falls, Inc. and Exergy Development Group ("UMX") Post-Hrg. Br. p. 9 (Oct. 22, 2012)). Since it establishes prices after 2015 solely based on a forecast of the coming three years, it is intrinsically biased toward immediate market trends. An environmental catastrophe could result in unrealistically high gas prices; in the current environment, its forecast appears unrealistically low.

Two intervenors, Hydrodynamics, Inc. and SolarPlexus, LLC ("HYDRO") and UMX argue respectively that either the natural gas price forecast adopted in the last avoided cost docket should be maintained, or that the Energy Information Administration ("EIA") forecast should be adopted whole. (*See* HYDRO Post-Hrg. Br. pp. 1, 3 (Nov. 13, 2012); Ex. UMX-1 p. 5). The first approach is untenable. In my view, the legal wrangling over whether to update an avoided cost tariff is not easily subject to a default to precedent. Statutes and administrative rules that are unchanging have good reason to be interpreted according to precedent; energy prices, less so. As to the UMX approach, it is tempting to adopt the EIA's Annual Energy

Outlook wholesale, but for its lack of specificity to AECO and transportation costs on the NorthWestern system.

The approach adopted in the Commission's Order, which is based on observed AECO market prices for natural gas and escalates with the fundamentals captured by the EIA, is consistent with the Commission's Order in the previous avoided cost proceeding and the advocacy of the Montana Consumer Counsel ("MCC"). Ord. 7108e at ¶¶ 58-70; (Ex. MCC-2 p. 17).

No party disputes that the ground has shifted fundamentally with the development of shale gas plays in our region and throughout the United States. Where the market will arrive is anyone's guess, as evidenced by the vast disparity between gas price forecasts offered in this proceeding. The only thing we know for certain about these forecasts is that they are wrong, and that the forecast the Commission relies on is either going to be too high or too low. *See* 9/12 Tr. at pp. 30-31. The Commission's method need only be reasonable, not perfect. *See* Mont. Code Ann. § 69-3-201 (2011). If I were asked if the results of that forecast are likely to be more often higher or lower than the actual future natural gas prices, I would surmise the forecast prices we rely on are an underestimate. As natural gas prices remain low, demand will be stimulated in sectors that are now underserved: More vehicles will be fueled by compressed natural gas; more homes and businesses will be heated by natural gas rather than electricity, propane, heating oil, or wood; more electric plants will be powered by natural gas, a trend of which NorthWestern's own plans to acquire a CCCT is symptomatic. The Commission rejects NorthWestern's over-simplistic estimate that natural gas prices will escalate merely based on the inflation index, and that decision ameliorates the underestimate of increased demand's effect of natural gas prices in some ways. *See supra* Ord. 7199d at ¶ 25. I am more trusting of the fundamentals-based EIA forecast, although even that is subject to annual recalibrations. It is unrealistic to expect a slow-moving Commission to establish "competitive" rates biennially. To counteract that lag, the rates the Commission establishes require an update next summer based on the methodology approved here. This approach offers the flexibility necessary to take account of the market's shifts, and mitigate errors inherent in the snapshot of prices and escalating factors which we momentarily adopt.

The Capacity Value of Intermittent Resources

One inevitable complication of establishing an avoided-cost rate based on the costs associated with a particular kind of power plant, like the CCCT/SCCT-derived Option 1 rates, is that the underlying plant has a unique operational character that may not be replicated by the QFs that may avail themselves of the rate. QFs in recent years have predominantly been sourced by wind, and these resources notably are not dispatchable—one cannot control the timing of their energy output, although one may be able to predict and measure it. The availability of resources during peak hours of demand, called capacity value, is an important issue in this proceeding. Clearly wind confers some capacity value, although probably quite little.

Admitted into the record are journal articles, surveys of utility practice, and other jurisdictions' consideration of the same matter. (*See* DR NWE-024–027 (June 12, 2012); Rev. DRs RNP-003, RNP-005 (Aug. 28, 2012); DR PSC-031–036 (Aug. 21, 2012)). Yet there is little detail adduced in evidence regarding NorthWestern's own system using the methods described in the professional literature, except for the fact that were the exceedance method to be applied to the NorthWestern, it might or it might not yield a capacity value for wind. The exceedance method determines capacity value based on the ratio of energy generated to installed capacity from the system's wind fleet in a selected amount of peak hours of the year. That determination is dependent on the identification of which hours are "peak" and the selection of a percentile level of hours at which to establish the exceedance threshold, choices that are subjective and open to dispute. (*See* 9/12 Tr. at pp. 96-98; Hrg. Transcr. pp. 189-193, 205-212 (Sept. 13, 2012) ("9/13 Tr.")). The criticism of the method offered by Michael Milligan and Kevin Porter, that it relies on the "arbitrary" selection of a percentile and the "fallacious use of probability theory," seems on point.[3] The Effective Load Carrying Capability method (ELCC), advocated in this proceeding by the Renewable Northwest Project (RNP), probably is the best method to measure the potential of a network of energy resources to serve load, and it does not seem unreasonable that it would be used to help establish avoided cost. (*See* 9/13 Tr. at pp. 184-185 (RNP witness Jimmy Lindsay providing a succinct description of the ELLC method)). NorthWestern has not done such a study. In my view, NorthWestern should do so. Because of

[3] *See* Michael Milligan & Kevin Porter, "The Capacity Value of Wind in the United States: Methods and Implementation," *The Electricity Journal*, Vol. 19, Issue 2, pp. 97-98 (Mar. 2006). The article in full appears in the evidentiary record in NorthWestern's Response to PSC-032c. (*See* DR PSC-032c pp. 7-8 (Aug. 21, 2012)).

the paucity of relevant evidence, it seems reasonable to defer to the judgment of regional experts, as the Commission did in its last avoided cost proceeding, and establish the capacity value of wind resources at 5% based on the work of the Northwest Power and Conservation Council. *See supra* Ord. 7199d at ¶ 52. The capacity payment embodied in the QF-1 Tariff should entirely compensate a plant for that attribute of availability which the industry terms capacity, and should cure any concern about wind's lack of dispatchability.

Other Issues Relating to the QF-1 Tariff

Although the record in this proceeding is not sufficiently developed to make judgments on certain topics or to warrant a departure from the Commission's methodology, the QF-1 Tariff is, in my view, unsound in some ways.

First, I would have been supportive of an avoided cost rate that used the Spion Kop acquisition as a proxy for an avoidable resource. While it is true that Spion Kop cannot be avoided, the basis for my approval of Spion Kop was the clear evidence that it was a least-cost, lowest-risk resource. *See* Ord. 7159l, Docket D2011.5.41, pp. 27-38 (Feb. 14, 2012). Since past Commission precedent holds that resources recently acquired can be reasonable proxies for avoided cost, it would not have been revolutionary to adopt this approach. *See* Ord. 6973d, Docket D2008.12.146, pp. 57-58 (Apr. 13, 2010). Yet when asked in data requests and during the live hearing about this proposition, none of the parties favored this approach in this proceeding. (*See e.g.* DR PSC-024e (July 11, 2012) ("Spion Kop should not be used as the basis for setting QF-1 rates"); *see also* 9/12 Tr. at pp. 136-138).

Second, the capacity rate embedded in Option 1 is bizarre because of its volumetric expression (being paid for through kilowatt-hours of energy rather than kilowatts of installed plant). A CCCT that NorthWestern would acquire, on the other hand, would be paid for its capacity regardless of whether or not it is running. It seems intuitive, then, that QFs should similarly be paid a fixed rate representing the resource's availability to the system.

Finally, and most importantly, the energy rates paid in Option 1 do not really reflect on-peak and off-peak differential observable in market prices. As UMX's witness Bill Pascoe observed, NorthWestern relies on the hourly market to supply its final increment, a price which may or may not be established by the cost of running a SCCT.[4] (*See* 9/13 Tr. at pp. 137-140). While I am sympathetic to his argument that wind should be paid on-peak energy rates when it produces during on-peak hours—the proposition is intuitive and obvious—his argument is as much an argument against the whole method underlying Option 1 rates, whose on-peak prices are really just the averaged price of the energy output of a CCCT added to a capacity payment expressed volumetrically. It seems unreasonable to pay wind such a capacity-driven rate.

Unfortunately, absent the establishment of a stronger on-peak/off-peak differential based on market prices, wind continues to be paid a relatively flat rate, which merely perpetuates the poorly targeted economic incentive established by the uniform payments per megawatt-hour of the federal production tax credit. The result has been to cause wind farms to locate where gross energy output is greatest, regardless of the time of day or year when they tend to produce energy.

On the other hand, an averaged, per megawatt-hour rate is straightforward and simple, and the Commission should not lose sight of the benefits of simplicity and straightforwardness in ratemaking, which at least one foundational author of ratemaking theory identifies as a hallmark of the field.[5] Although it will lead to paying wind farms for some hours that are above market and some hours that are below market, that proposition is hardly unique to QF proceedings or wind farms. NorthWestern's other power purchase agreements and rate-based assets are characterized by averages that do not reflect real market values in similar, if not the same, ways. NorthWestern's contracts with power marketers such as PPL-Montana are often on a per megawatt-hour cost basis, and they frequently cost more than the hourly market. It is PPL-Montana's choice to determine which of their assets to run—or whether to buy on the market—to supply NorthWestern energy under its contract, whose price does not depend on PPL-Montana's choice and attendant costs. Meanwhile, customers pay for rate-based assets such as Colstrip Unit 4 even when it generates no electricity at all.[6] Without exceptional and unheard-of

[4] Potentially, Option 1(a) could pay accurate off-peak and on-peak prices, but only on the assumption that on-peak prices over the long term would be established by SCCTs in the region acting as the marginal units of production, thereby establishing the market price. In this case, Option 1(c) would not properly compensate wind, and in any case it is clear that the Option 1 rates are meant to compensate energy *and* capacity, with energy being paid an average, per megawatt-hour rate.

[5] J.C. Bonbright, *Principles of Public Utility Rates*, pp. 290-294 (New York: Columbia University Press, 1961).

[6] The QF developer, meanwhile, bears all the risk for the facility's performance. If the wind regime is not as good as projected, there is no risk to the utility or its customers. On the other hand, if the wind regime is better than projected, ratepayers obtain no benefit, while they would reap that benefit from a rate-based asset.

good luck, every long-term contract or rate-based asset will in some, and often numerous, hours look uneconomic.

The 50 Megawatt Installed Capacity Limit

Also included for approval in NorthWestern's QF-1 Tariff is the 50 megawatt ("MW") installed capacity limit. Although it has appeared in the QF-1 Tariff for several years, only recently has it been used to stifle negotiations with QFs.

In addition to addressing the merits of the question, NorthWestern has also questioned whether the 50 megawatt installed capacity limit is a duly noticed issue in this proceeding. (*See Ex.* NWE-2 p. 29). One need only scratch the surface of this argument to reveal that it is misplaced. NorthWestern, in filing its application, appended in its entirety the QF-1 Tariff for Commission approval. The choice to append the entire tariff for approval established the parameters of the proceeding, which is the QF-1 Tariff in whole. General intervenors have a right to address anything within the four corners of that tariff. *See* Admin. R. Mont. 38.2.2403. Anything in that tariff is potentially at issue in this proceeding, and clearly is at issue when an intervenor chose to address it directly in its direct testimony and noticed it as an issue in its pre-hearing memorandum, and when the utility then responded to it in pre-filed rebuttal testimony, at the live hearing, and in post-hearing briefing. (Ex. UMX-1 pp. 26-33; Ex. NWE-2 pp. 29-35; 9/12 Tr. at pp. 118-119, 165-172; UMX Pre-Hrg. Memo. p. 4 (Aug. 28, 2012); UMX Post-Hrg. Br. at pp. 25-26; NWE Initial Post-Hrg. Br. p. 13 (Oct. 22, 2012); UMX Post-Hrg. Response Br. p. 10 (Nov. 13, 2012); NWE Post-Hrg. Response Br. p. 7 (Nov. 13, 2012)). If it considered the capacity limit not to be at issue, then NorthWestern, in any case, waived this argument by never moving to strike the portions of intervenor testimony that addressed it. Nor did NorthWestern object to the questioning of its witnesses about the topic.

Were the Commission to contrive to find that the 50 MW installed capacity limit was not at issue in this proceeding, it would set a dangerous, anti-consumer precedent for future Commission proceedings. Imagine, for instance, NorthWestern arguing in the context of a rate case that, no matter what was contained within the voluminous statements and workpapers appended to its application, only matters directly addressed in NorthWestern witnesses' pre-filed testimony were properly at issue. All manner of real issues that are frequently never addressed in direct testimony but are included in the workpapers or as costs recovered in proposed tariffs—

executive compensation or advertising or pension costs, for instance—would under this unusual theory not be "issues" in the proceeding, even if the Montana Consumer Counsel remarked upon them in its testimony, and even though NorthWestern sought recovery of those costs through a tariff appended to the application. The Commission must not countenance attempts to obfuscate important matters in a fog of process that would ultimately handcuff the Consumer Counsel and the Commission and prevent them from doing their jobs. The consideration of this issue has been deep. Due process has been plentiful. The Commission simply does not have a choice to ignore the merits of the arguments on this issue.

Moving to a consideration of the 50 megawatt installed capacity limit for what it is—a policy and substantive legal issue of this proceeding—there can be no real justification for it as a policy matter unless one of several things is true: (1) The QF rate to which the limit applies is based on a specific carve-out for resources that the utility needs only some certain quantity of under a state law like the renewable portfolio standard; (2) the utility does not need more energy, lest it be oversupplied; or (3) the utility has clearly exhausted its capability to integrate new intermittent generators onto its grid. None of these conditions exist.

The first is no longer true. As observed above, all of the rates available to wind generators are based on the cost of a natural-gas-fired generator, against which wind should be allowed to compete. The second point is also not the case. Clearly NorthWestern has an abiding need for additional electric generating resources. *See* 2011 Plan at pp. 136-137. As NorthWestern often observes, it controls fewer resources compared to its peers, and buys a great deal of energy from short- or mid-term contracts or on the spot market. *See id.* at p. 3. The final consideration—whether NorthWestern can reliably integrate new intermittent generators onto the grid—is a real consideration. That concern, however, is addressed and substantially resolved through the wind integration tariff, Schedule WI-1 ("WI-1 Tariff"), discussed further below. The WI-1 Tariff approved in this proceeding properly reflects the economic consequences of integrating wind onto the grid. The ability to integrate new intermittent resources presents an economic question, and we should not answer an economic question with a legal artifice that bears little relation to the utility's ability to integrate wind.

Beyond the policy issues, the 50 megawatt installed capacity limit as written is manifestly unlawful, as NorthWestern's own witness conceded at the hearing. (*See* 9/12 Tr. at pp. 119, 165-166). So long as NorthWestern requires either energy or capacity or both, avoided cost rates must allow independent generators the opportunity to sell to NorthWestern and its customers. I cannot in good conscience ignore both the law and good public policy in pretending that either countenances this tariff provision, which would have the effect of short-circuiting every other carefully considered matter in this proceeding.

THE WI-1 TARIFF

Until now, NorthWestern has estimated the integration needs of wind resources and charged QFs for integration service based on a certain percentage—in this case 18%—of a facility's total nameplate capacity. The evidence in this record clearly establishes that this *pro rata* methodology is flawed, unreasonable, and must be discarded.

Thanks to the work of NorthWestern, various wind developers, and GENIVAR Consultants Limited Partnership ("GENIVAR"), a study of wind's variability and its impact on integration needs has been conducted and thoroughly vetted. (*See* DR UMX-017 Attachment 4 (Mar. 30, 3012)). The GENIVAR study shows enormous disparities in the amount of integration service wind farms need. If located diversely from other wind assets, new wind QFs do not significantly increase integration needs, and may actually *decrease* the need for this service. Meanwhile, wind QFs locating near existing wind farms do impose a proportionally large need for integration. In place of the *pro rata* method, UMX's witnesses Mr. Pascoe and Brendan Kirby favor the error contribution methodology, which determines which wind farms tend to exacerbate sudden wind ramps on the system and which wind farms have a countervailing tendency, and then allocates the costs and benefits of that diversity (or non-diversity) to various wind farms based on the degree to which their energy production is causing the need for integration service to increase. (*See* Ex. UMX-1 pp. 15-16; Ex. UMX-3 p. 4). That approach is precise and appropriate in many contexts. *See Integration of Variable Energy Resources*, 139 F.E.R.C. ¶ 61,246, pp. 222-223 (June 22, 2012) (suggesting wind generators should share diversity benefits). However, in this proceeding the incremental method, which allocates wind integration costs based on the additional amount of integration required by the addition of a new facility, is simpler and more in line with QF law, which requires us to determine the utility's incremental or avoided cost. It is therefore appropriate that wind resources be charged a WI-1 Tariff reflective of the burden they impose incrementally.

Whichever methodology we adopt, it is a fact that a wind farm's actual integration needs cannot be known until it begins to operate. The Commission has adopted UMX's proposal for a predictive WI-1 Tariff with three zones, making certain revisions based on the results of the GENIVAR study. As far as I know, this zonal wind integration tariff is the first of its kind, and will provide a useful counterweight to federal and state incentives that otherwise lead wind farms to locate wherever gross energy output is greatest, even while they may disproportionately increase integration needs on the system.

While the rates charged under the WI-1 Tariff may not be enough to dissuade developers from locating near existing wind farms, it is possible that the zonal integration charges could further diverge from one another in future proceedings. If NorthWestern appears to be at risk of violating reliability standards, then the Commission could suspend the availability of the WI-1 Tariff for Zone 1 and require wind farms in that zone to self-supply regulation service from the market in order to pass along a true market cost of that service. As approved, the WI-1 Tariff now provides a framework for pricing integration service, albeit one that must change as new wind farms are added to the system.

The evidence in this proceeding also suggests there are many ways that NorthWestern could get more value out of the Dave Gates Generating Station (DGGS), which provides integration services for NorthWestern's customers. Mr. Kirby testified that better forecasting, intra-hourly scheduling, and consolidation of balancing areas would enable integration of large amounts of wind with the same integration resources. (9/12 Tr. at pp. 325-329; Ex. UMX-3, *passim*). The GENIVAR study corroborates those observations as they relate to scheduling and forecasting. While concerns about DGGS' running out of capacity at some point may be valid, these ways of freeing up additional capacity suggest that the WI-1 Tariff should be based on the marginal cost of running the DGGS.[7]

CONCLUSION

The essential point of this proceeding is to set rates that reflect the utility's avoided cost; set accordingly, avoided cost rates will act as a natural barrier to uneconomic resources. Barriers should be economic in nature. They should not be hard and fast rules that discriminate against

[7] To do otherwise would cause the rates for QFs to diverge from the assumptions imputed to Spion Kop. Ord. 71591 at pp. 29-30. Moreover, to create an economically efficient price signal, it is necessary to price regulation service based on the utility's marginal cost. *See supra* n. 1 (setting forth Alfred Kahn's reasoning).

independent producers even while the utility helps itself to greater levels of owned generation. The Commission's Order in this matter is one small step toward a dose of competition—one that is healthy for customers in a market that would otherwise be utterly shuttered to the competitive forces that drive costs down, keep monopoly impulses in check, and ultimately benefit those paying the bill.

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TRAVIS KAVULLA, Chairman (concurring)